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August 8, 2006

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: NSTAR Electric Company, D.T.E. 06-40

Dear Secretary Cottrell:

Enclosed for filing in the above-referenced matter are the responses to the Information Requests set forth on the accompanying list.

Thank you for your attention to this matter.

Sincerely,

Robert N. Werlin

Enclosures

cc: Service List

Responses to Information Requests

AG-4-3
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Information Request AG-4-3

Please refer to the response to DTE-2-8. Please identify all 13.8kV upgrades, modifications or other projects that were completed by Cambridge between 1997 and the present that relate to providing services to a single customer or of a single contiguous property (Biogen, Harvard, MIT, Town of Belmont, MBTA, Mirant, etc.). For each project, include a brief description of the project, the in service date, the total project cost, the 2006 revenue requirement and the amount each customer contributed to the cost of each project. For each year each project has been in service, provide the LNS or special contract revenues the Company has received from each of the primary beneficiaries. Provide all supporting documentation (including copies of all contracts for services provided over the new 13.8kV facilities), workpapers, calculations, and assumptions.

Response

831-1385

Installed 700 MCM 15 kV EPR power cable (7,288 ft.) from station 831 (Putnam) to station 832.
Also bifurcated circuits 831-1323 and 831-1336 to become 831-1336XY
Date in service: June 7, 2004
Cost: $262,466
CIAC Revenue Credit: $290,000
Customer Contribution : None
2006 Annual Revenue Requirement: $48,373

Transmission Revenues (includes LNS and RNS costs)[1]
Year 2004 = $885,110
Year 2005 = $1,395,348

875-1389

Installed 250 feet of duct bank and 3,850 feet of 15 kV cable through 14 existing manholes in Cambridge, from Station 875 to customer at 555 Technology Square.
Date Energized: March 18, 2006
Cost: $264,364
Customer Contribution: $264,364
2006 Annual Revenue Requirement: $16,529

[1] The Companies do not separately track LNS revenues paid by individual retail customers. All retail customers pay the same transmission rate established by the Department in their annual transmission filings, which include LNS, RNS and other regional costs. None of the customers has special contracts except the Town of Belmont.

875-1392	Install 2,900 feet of 15 kV cable through 12 existing manholes in Cambridge, from Station 875 to customer at 1 Cambridge Center, Building 6A, (Binney St). Date Energized: December 15, 2006 Cost: $771,031.00 Customer Contribution: $771,031.00 2006 Annual Revenue Requirement: $48,209
831-1111 831-1112 831-1113	Install 5,259 feet, 5,413 feet, and 5,599 feet of 15 kV cable through existing duct line and manholes in Cambridge, from Station 831 Putnam to customer Station 866 on Holyoke St. Date Energized: Dec. 1999 to Feb. 2000 Cost: $1,252,204 CIAC Revenue Credit: $1,252,204 Customer Contribution: None 2006 Annual Revenue Requirement: $230,786 Transmission Revenues (includes LNS and RNS costs) Year 1999 = $794,757 Year 2000 = $584,064 Year 2001 = $1,338,317 Year 2002 = $778,765 Year 2003 = $1,764,911 Year 2004 = $1,277,144 Year 2005 = $1,918,030
828-1325	Install 4,536 feet of 15 kV triplexed 500 MCM EPR cable in an existing duct and manhole system in Cambridge from station #828 Alewife to a manhole on the Belmont town line for connection to a cable installed by Belmont Municipal Light. Date Energized: February, 10, 2000 Cost: $200,780 Customer Contribution: None (Wholesale Special Contract) 2006 Annual Revenue Requirement: $37,005

The total special contract revenues received from the Town of Belmont consisted of revenues provided under the Net Requirements Agreement ("NRA") and the Transmission Service Agreement ("TSA"). The Net Requirements Agreement obliged Cambridge to provide bundled capacity, energy and transmission delivery for the Town of Belmont's total requirements until March 31, 2003 with the exception of a small amount of wheeling of power from the Power Authority of the State of New York which was provided under the provisions of the TSA. Once the NRA expired on April 1, 2003, Cambridge provided the Town of Belmont with only transmission delivery service under the TSA for wheeling power to Belmont from all of its generation sources. The special contract revenues for the Town of Belmont beginning in 2000 are as follows:

Belmont:

Year 2000	NRA Revenues = $6,794,034, TSA Revenues = $193,503
Year 2001	NRA Revenues = $6,876,645, TSA Revenues = -$326,503 (Refund)
Year 2002	NRA Revenues = $7,326,660, TSA Revenues = $73,383
Year 2003	NRA Revenues = $1,950,987, TSA Revenues = $584,072
Year 2004	TSA Revenues = $1,014,511
Year 2005	TSA Revenues = $1,032,741

Please refer to Attachment AG-4-3(a) for estimates of the 2006 revenue requirement associated with each of the project capital costs. As indicated in the attachment, the revenue requirement for each project was estimated by multiplying the capital investment in the project by a carrying charge computed as the ratio of the revenue requirement for all of Cambridge's 13.8 kV facilities (as computed in Exhibit NSTAR-CLV-7) to the total plant cost for Cambridge's 13.8 kV facilities. Where the customer provides the full contribution to the cost of the project, the revenue requirement for that project was estimated by multiplying the capital investment in the project by a carrying charge computed as the ratio of the O&M related costs to the total plant costs for Cambridge's 13.8 kV facilities.

Please refer to Attachment AG-4-3(b), which sets forth the development of the Revenue Credit as applicable to the indicated customers (lines), above.

Determination of the 2006 Revenue Requirement
13.8 kV projects for Single Customers

Customer/13.8 kV line	Project Capital Cost	Carrying Charge	2006 Revenue Requirement
Retail Customer A			
Line 831-1385	$262,466	0.184303793 (1)	$48,373
Retail Customer B			
Line 875-1389	$264,364	0.062525373 (2)	$16,529
Retail Customer C			
Line 875-1392	$771,031	0.062525373 (2)	$48,209
Retail Customer D			
Line 831-1111			
Line 875-1112			
Line 875-1113			
Total	$1,252,204	0.184303793 (1)	$230,786
Town of Belmont			
Line 828-1325	$200,780	0.184303793 (1)	$37,005

Note (1) Carrying Charge Rate is based upon the 13.8 kV facilities revenue requirement analysis provided in Exhibit NSTAR CLV-7.

Carrying Charge Rate = 13.8 kV revenue requirement / 13.8 kV plant ($13,421,298 / $72,821,605)

Note (2) Carrying Charges include only O&M related costs since no capitalized plant investment due to customer contribution.

Carrying Charge Rate = 13.8 kV revenue requirement / 13.8 kV plant ($4,553,198 / $72,821,605)

Determination of the Revenue Credit
13.8 kV projects for Single Customers

Customer	Analysis Year	Square Footage	Watts/SF	Incremental kW	CIAC Revenue(1) Credit Factor($/kW)	Revenue Credit
Reatil Customer A						
Line 831-1385	2002	660,000	4	2,640	$110	$290,400
Retail Customer D						
Line 831-1111						
Line 875-1112						
Line 875-1113						
Total (2)	2000					$1,252,204

Information Request AG-5-4

Refer to Exhibit NSTAR-CLV-1, page 18, lines 9-18. Please describe the work that needs to be done in order to transfer the Cambridge load to the new East Cambridge Substation.

a. When will this transfer be completed?

b. What is the estimated load that will be transferred, in kW and kWh? Please provide the load data by customer class.

c. What is the 2006 cost of the related capital projects and how will these costs be recovered from customers?

d. When will the SCR/RMR payments to Mirant Kendall terminate? When did NSTAR officially notify Mirant that the Kendall station would not been needed for local reliability? What is the required notice period?

e. What is the current monthly SCR/RMR costs for the Mirant Kendall Station? If there are no payments being made, what was the cost for 2006?

Response

a. The transfers will be performed after the second 115 kV circuit is successfully installed from Putnam Station to East Cambridge Station. The installation has become far more complicated than originally planned since numerous obstructions have been encountered in the conduit system between Putnam and East Cambridge Stations, which resulted in damage to cables being installed. There have been several attempts to locate and overcome these obstructions in a non-invasive manner. NSTAR Electric is conducting an extensive and detailed investigation to resolve these obstructions and the timing of their resolution is not yet available.

b. The anticipated 2007 Cambridge peak kW of the distribution circuits that will be transferred from Station #850 to the new station is 48 MW. An additional 23 MW is planned to be transferred off Station #850 to Putnam Station by using the old intra-ties as radial circuits by opening the breakers at the Prospect Station #819. The transferred kW and kWh are assumed to have the same customer characteristics as the whole Cambridge system. The demand and energy breakdown by customer class for Cambridge is as follows:

Customer Class	Demand (kW)	Energy (kWh)
Residential	7,800	41,646,000
Small C&I	13,600	60,584,000
Large C&I	49,500	250,331,000

c. The 2006 expenditures were $1.75 million up to June, 2006. Additional costs are not known for the remainder of the year, until there is a resolution to the 115 kV cable pulling procedures described above. The estimated costs for the project, for the year 2006, will be recovered through the transmission rates. The estimated costs will be reconciled to actual costs for the year 2006. Any additional costs capitalized thereafter in the years following 2006 will be recovered in the transmission rates for only those facilities that operate at 115 kV and above.

d. The timing of when the SCR/RMR payments will be terminated is dependent on the completion of the second transmission line to the new station. NSTAR Electric will notify the ISO-NE and Mirant that the Kendall generation would not be needed for local reliability after resolution of the 115 kV cable installation issue. The contractual notice period is 120 days.

e. Refer to the response provided to Information Request CLC-1-6 where for projections for the 2006 monthly costs stemming from the Mirant Kendall SCR/RMR contracts. These charges will vary from month to month depending upon several factors. As discussed in the response to Information Request AG-3-2, NSTAR Electric negotiated a settlement that resulted in significant reductions in the monthly fixed RMR costs and the variable SCR costs. Monthly fixed costs were reduced from the filed rate of $13.7 million to $7.9 million. SCR charges are incurred only when the units are required by Cambridge to run out of economic merit order for local reliability needs and have not already been dispatched in tandem with Mirant's combustion turbine.

Information Request AG-5-7

Please provide current estimates of the of pension adjustment factor costs, including reconciliation of prior period under/over recoveries at December 31, 2006, for each Company. Include all supporting workpapers, calculations and assumptions.

Response

Please refer to Attachment AG-5-7 for the current forecast of the 2007 Pension Adjustment Factor Calculation. This calculation includes seven months of actual and five months of forecast activity for the year 2006.

2007 Pension Adjustment Factor Calculations ($'s in millions)

Line	Description	NSTAR Electric	NSTAR Gas	Total	Reference
	Col. A	Col. B	Col. C	Col. D	Col. E
	RECONCILIATION ADJUSTMENT				
1	2006 Pension & PBOP Distribution Expense	$ 18.750	$ 6.723	$ 25.473	Page 5, Line 26
2	Base Rate Pension & PBOP Expenses for distrib & transm	$ 32.609	$ 4.818	$ 37.427	Page 5, Line 28
3	2006 transmission allocator (est.)	6.65%	0.00%		1 + Line 4 / Line 2
4	less: Pension and PBOP currently in rates	$ (30.440)	$ (4.818)	$ (35.258)	Page 5, Line 30
5	2006 Reconciliation Deferral	$ (11.689)	$ 1.905	$ (9.784)	Line 1 + Line 4
6	2005 Reconciliation Deferral	$ (8.963)	$ 2.882	$ (6.081)	Page 2, Line 5
7	2004 Reconciliation Deferral	$ (4.505)	$ 4.208	$ (0.297)	Page 3, Line 5
8	Total Reconciliation Deferral	$ (25.157)	$ 8.995	$ (16.162)	Line 5 + Line 6 + Line 7
9	**Reconciliation Amortization**	**$ (8.386)**	**$ 2.998**	**$ (5.387)**	Line 8 / 3
10	Unamortized Reconciliation Deferral at 12/31/2006 (est.)	$ (10.780)	$ 2.231	$ (8.550)	Line 5*2/3 + Line 6*1/3
	CARRYING CHARGE				
11	Cost of Capital Factor	10.88%	10.88%	10.88%	Per D.T.E. 03-47-A (Note 1)
12	Allocation Factors 2006 (less unregs)	78.73%	20.58%		
13	Actual Pension Prepaid at 12/31/2005 (Note 2)	$ 256.301	$ 67.006	$ 323.307	Page 2, Line 16
14	Estimated Pension Prepaid at 12/31/2006			$ 321.882	BECO A/C 165010
15	Allocated Amounts (less unregs)	$ 253.407	$ 66.249	$ 319.656	Line 14 *Line 12
16	Estimated Pension Prepaid at 12/31/2006 (less transmission)	$ 237.825	$ 62.175	$ 300.000	Line 15 * (1-Page 5,Line 10) (BECO only)
17	2006 Average Pension Prepaid	$ 247.063	$ 64.591	$ 311.654	(Line 13 + Line 16) / 2
18	Deferred Tax on Pension	$ (79.467)	$ (20.775)	$ (100.242)	Line 17 * 0.82 * 0.39225
19	Pension Balance Subject to Carrying Charge	$ 167.597	$ 43.815	$ 211.412	Line 17 + Line 18
20	Actual PBOP Prepaid at 12/31/2005	$ (36.942)	$ (9.658)	$ (46.600)	Page 2, Line 22
21	Estimated PBOP Prepaid at 12/31/2006 (for all companies)			$ (69.259)	NSTAR A/C 242500
22	Allocated Amounts (less unregs)	$ (54.525)	$ (14.255)	$ (68.780)	Line 21 * Line 12
23	2006 Average PBOP Prepaid	$ (45.734)	$ (11.956)	$ (57.690)	(Line 20 + Line 22)/2
24	Deferred Tax on PBOP	$ 14.889	$ 3.893	$ 18.782	Line 23* 0.83 * 0.39225 * -1
25	Medicare Act Impact as of 12/31/2005			$ 9.659	Page 2, Line 26
26	Medicare Act Impact as of 12/31/2006 (est.)			$ 11.400	Page 5, Line 16
27	2006 Average Balance			$ 10.529	(Line 25 + Line 26)/2
28	Allocated Amounts (less unregs)	$ 8.289	$ 2.167	$ 10.457	Line 27 * Line 12
29	Medicare Deferred Tax Adjustment	$ 3.252	$ 0.850	$ 4.102	Line 28 * 0.39225
30	PBOP Balance Subject to Carrying Charge	(27.593)	(7.214)	(34.806)	Line 23 + Line 24 + Line 29
31	**Carrying Charge on Average Prepaid**	**$ 15.232**	**$ 3.982**	**$ 19.215**	(Line 19 + Line 30)*Line 11
32	Unamortized Reconciliation Deferral for 2006	$ (19.166)	$ 5.229	$ (13.937)	Page 2, Line 10 + Line 5
33	Deferred Tax Amount	$ 7.518	$ (2.051)	$ 5.467	Line 32 * 0.39225 *-1
34	Balance Subject to Carrying Charge	$ (11.648)	$ 3.178	$ (8.470)	Line 32 + Line 33
35	**Carrying Charge on Deferral Balance**	**$ (1.267)**	**$ 0.346**	**$ (0.922)**	Line 34 * Line 11
36	**Total Carrying Charges**	**$ 13.965**	**$ 4.328**	**$ 18.293**	Line 31 + Line 35
	PAST PERIOD RECONCILIATION AMOUNT				
37	2006 Pension/PBOP Adjustment Amount	$ 11.819	$ 8.870	$ 20.688	Page 2, Line 42
38	less: 2006 Pension/PBOP Adjustment Revenue	$ (9.886)	$ (6.902)	$ (16.788)	Page 5, Line 32
39	Prior Period Reconciliation Amount	$ 1.933	$ 1.968	$ 3.901	Line 37 + Line 38
40	Interest at Prime Rate 8.254%	$ 0.160	$ 0.162	$ 0.322	Prime rate as per 220 § 6.08(2)*Line 39
41	**Past Period Reconciliation Amount**	**$ 2.092**	**$ 2.130**	**$ 4.223**	Line 39 + Line 40
	TOTAL				
42	**Actual Pension/PBOP Adjustment Amount**	**$ 7.672**	**$ 9.457**	**$ 17.128**	Line 9 + Line 36+ Line 41
43	Forecasted 2007 gWh (Mil Therms for NSTAR Gas)	-	-		
44	**2007 Pension/PBOP Adjustment Factor**				

Note 1: This before-tax factor is equal to the after-tax factor of 8.16 percent authorized by the Department.

Note 2: The balances have been reduced to eliminate the amount recovered from transmission customers and non-utility businesses

2006 Pension Adjustment Factor Calculations ($'s in millions)

Line	Description	Boston Edison	Cambridge Electric	Commonwealth Electric	NSTAR Gas	Total	Reference
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G
	RECONCILIATION ADJUSTMENT						
1	2005 Pension & PBOP Distribution Expense	$ 14.693	$ 0.732	$ 6.051	$ 7.700	$ 29.177	Reference: 05-90
2	Base Rate Pension & PBOP Expenses for distrib & transm	$ 24.031	$ 1.207	$ 7.371	$ 4.818	$ 37.427	Company Records (03-47; AG-1-31 (Att))
3	2005 transmission allocator	6.15%	35.29%	3.61%	-		Reference: 05-90
4	less: Pension and PBOP currently in rates	$ (22.553)	$ (0.781)	$ (7.105)	$ (4.818)	$ (35.258)	Line 2 * (1-Line 3)*-1
5	2005 Reconciliation Deferral	$ (7.860)	$ (0.049)	$ (1.054)	$ 2.882	$ (6.081)	Line 1 + Line 4
6	2004 Reconciliation Deferral	$ (5.092)	$ (0.157)	$ 0.745	$ 4.208	$ (0.297)	Page 3, Line 5
7	2003 & 2002 Reconciliation Deferral	$ 6.338	$ 3.887	$ 1.758	$ 3.050	$ 15.033	Page 4, Line 1+ Page 4, Line 4
8	Total Reconciliation Deferral	$ (6.614)	$ 3.682	$ 1.449	$ 10.140	$ 8.656	Line 5 + Line 6 + Line 7
9	**Reconciliation Amortization**	**$ (2.205)**	**$ 1.227**	**$ 0.483**	**$ 3.380**	**$ 2.885**	Line 8 / 3
10	Unamortized Reconciliation Deferral at 12/31/2005	$ (6.938)	$ (0.085)	$ (0.454)	$ 3.324	$ (4.153)	Line 5*2/3 + Line 6*1/3
	CARRYING CHARGE						
11	Cost of Capital Factor	10.88%	10.88%	10.88%	10.88%	10.88%	Per D.T.E. 03-47-A (Note 1)
12	Allocation Factors 2005 (less unregs)	54.70%	4.19%	19.84%	20.58%		Reference: 05-90
13	Actual Pension Prepaid at 12/31/2004 (Note 2)	$ 155.552	$ 8.434	$ 54.153	$ 56.051	$ 274.190	Page 3, Line 11
14	Actual Pension Prepaid at 12/31/2005					$ 346.889	BECO A/C 165010
15	Allocated Amounts (less unregs)	$ 189.740	$ 14.531	$ 68.822	$ 71.396	$ 344.490	Line 14 *Line 12
16	Actual Pension Prepaid at 12/31/2005 (less transmission)	$ 178.073	$ 13.638	$ 64.591	$ 67.006	$ 323.307	Line 15 * (1-Line 3) (BECO only)
17	2005 Average Pension Prepaid	$ 166.813	$ 11.036	$ 59.372	$ 61.529	$ 298.749	(Line 13 + Line 16) / 2
18	Deferred Tax on Pension	$ (53.654)	$ (3.550)	$ (19.097)	$ (19.790)	$ (96.091)	Line 17 * 0.82 * 0.39225
19	Pension Balance Subject to Carrying Charge	$ 113.158	$ 7.486	$ 40.275	$ 41.738	$ 202.658	Line 17 + Line 18
20	Actual PBOP Prepaid at 12/31/2004	$ (34.092)	$ (1.848)	$ (11.869)	$ (12.285)	$ (60.094)	Page 2, Line 16
21	Actual PBOP Prepaid at 12/31/2005 (for all companies)					$ (46.924)	NSTAR A/C 242500
22	Allocated Amounts (less unregs)	$ (25.666)	$ (1.966)	$ (9.310)	$ (9.658)	$ (46.600)	Line 21 * Line 12
23	2005 Average PBOP Prepaid	$ (29.879)	$ (1.907)	$ (10.589)	$ (10.971)	$ (53.347)	(Line 20 + Line 22)/2
24	Deferred Tax on PBOP	$ 9.728	$ 0.621	$ 3.447	$ 3.572	$ 17.368	Line 23* 0.83 * 0.39225 * -1
25	Medicare Act Impact as of 12/31/2004					$ 7.000	Per Company Records
26	Medicare Act Impact as of 12/31/2005					$ 9.659	Per Company Records
27	2005 Average Balance					$ 8.329	(Line 25 + Line 26)/2
28	Allocated Amounts (less unregs)	$ 4.556	$ 0.349	$ 1.653	$ 1.714	$ 8.272	Line 27 * Line 12
29	Medicare Deferred Tax Adjustment	$ 1.787	$ 0.137	$ 0.648	$ 0.672	$ 3.245	Line 28 * 0.39225
30	PBOP Balance Subject to Carrying Charge	(18.365)	(1.149)	(6.493)	(6.727)	(32.734)	Line 23 + Line 24 + Line 29
31	**Carrying Charge on Average Prepaid**	**$ 10.314**	**$ 0.689**	**$ 3.675**	**$ 3.809**	**$ 18.488**	(Line 19 + Line 30)*Line 11
32	Unamortized Reconciliation Deferral for 2005	$ (9.142)	$ 1.143	$ 0.028	$ 6.704	$ (1.267)	Page 3, Line 8 + Line 5
33	Deferred Tax Amount	$ 3.586	$ (0.448)	$ (0.011)	$ (2.630)	$ 0.497	Line 32 * 0.39225 *-1
34	Balance Subject to Carrying Charge	$ (5.556)	$ 0.694	$ 0.017	$ 4.074	$ (0.770)	Line 32 + Line 33
35	**Carrying Charge on Deferral Balance**	**$ (0.605)**	**$ 0.076**	**$ 0.002**	**$ 0.443**	**$ (0.084)**	Line 34 * Line 11
36	**Total Carrying Charges**	**$ 9.709**	**$ 0.765**	**$ 3.677**	**$ 4.253**	**$ 18.404**	Line 31 + Line 35
	PAST PERIOD RECONCILIATION AMOUNT						
37	2005 Pension/PBOP Adjustment Amount	$ 8.065	$ 1.945	$ 4.901	$ 6.997	$ 21.908	Page 3, Line 32
38	less: 2005 Pension/PBOP Adjustment Revenue	$ (9.362)	$ (2.093)	$ (5.184)	$ (5.834)	$ (22.473)	Per Company Records
39	Prior Period Reconciliation Amount	$ (1.297)	$ (0.148)	$ (0.283)	$ 1.163	$ (0.565)	Line 37 + Line 38
40	Interest at Prime Rate 6.363%	$ (0.083)	$ (0.009)	$ (0.018)	$ 0.074	$ (0.036)	Prime rate as per 220 § 6.08(2)*Line 39
41	**Past Period Reconciliation Amount**	**$ (1.380)**	**$ (0.158)**	**$ (0.301)**	**$ 1.237**	**$ (0.601)**	Line 39 + Line 40
	TOTAL						
42	**Actual Pension/PBOP Adjustment Amount**	**$ 6.125**	**$ 1.834**	**$ 3.860**	**$ 8.870**	**$ 20.688**	Line 9 + Line 36+ Line 41

Note 1: This before-tax factor is equal to the after-tax factor of 8.16 percent authorized by the Department.

Note 2: The balances have been reduced to eliminate the amount recovered from transmission customers and non-utility businesses

2005 Pension Adjustment Factor Calculations ($'s in millions)

Line	Description	Boston Edison	Cambridge Electric	Commonwealth Electric	NSTAR Gas	Total	Reference
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G
1	Unamortized Reconciliation Deferral at 12/31/2003	$ 4.225	$ 2.591	$ 1.172	$ 2.033	$ 10.022	Page 4, Line 7
2	2003 Reconciliation Amortization	2.113	1.296	0.586	1.017	5.011	Line 1*0.5 (2nd year of 3-year amortization)
3	2004 Pension & PBOP Distribution Expense	17.278	0.797	7.823	9.026	34.925	Reference: 04-118
4	less: Pension & PBOP Expense Currently in Distrib Rates	(22.371)	(0.954)	(7.079)	(4.818)	(35.221)	Reference: 04-118*-1
5	2004 Reconciliation Deferral	(5.092)	(0.157)	0.745	4.208	(0.297)	Line 3 + Line 4
6	2004 Reconciliation Amortization	(1.697)	(0.052)	0.248	1.403	(0.099)	Line 5 / 3 (1st year of 3-year amortization)
7	Reconciliation Adjustment For 2005	$ 0.415	$ 1.243	$ 0.834	$ 2.419	$ 4.912	Line 2 + Line 6
8	Unamortized Reconciliation Deferral at 12/31/2004	$ (1.282)	$ 1.191	$ 1.082	$ 3.822	$ 4.813	Line 1 + Line 5- Line 7
	Carrying Charge Calculation:						
9	Cost of Capital Factor	10.88%	10.88%	10.88%	10.88%	10.88%	Per D.T.E. 03-47-A (Note 1)
10	Actual Pension Prepaid at 12/31/2003 (Note 2)	157.912	8.124	55.385	53.835	275.256	Page 4, Line 11
11	Actual Pension Prepaid at 12/31/2004 (Note 2)	155.552	8.434	54.153	56.051	274.190	Reference: 04-118
12	2004 Average Pension Prepaid	156.732	8.279	54.769	54.943	274.723	(Line 10 + Line 11) / 2
13	Deferred Tax on Pension	(50.412)	(2.663)	(17.616)	(17.672)	(88.363)	Line 12 * .82 * 0.39225
14	Pension Balance Subject to Carrying Charge	$ 106.320	$ 5.616	$ 37.153	$ 37.271	$ 186.360	Line 12 + Line 13
15	Actual PBOP Prepaid at 12/31/2003	$ (29.970)	$ (1.542)	$ (10.511)	$ (10.217)	$ (52.240)	Page 4, Line 16
16	Actual PBOP Prepaid at 12/31/2004	(34.092)	(1.848)	(11.869)	(12.285)	(60.094)	Reference: 04-118
17	2004 Average PBOP Prepaid	(32.031)	(1.695)	(11.190)	(11.251)	(56.167)	(Line 15 + Line 16) / 2
18	Deferred Tax on PBOP	10.428	0.552	3.643	3.663	18.286	Line 17 * .83 * 0.39225
19	Deferred Tax Adjustment for Medicare Act	0.770	0.042	0.268	0.278	1.358	$7/2* 0.39225* 2004 allocation factors
20	PBOP Balance Subject to Carrying Charge	$ (20.832)	$ (1.101)	$ (7.279)	$ (7.310)	(36.523)	Line 17 + Line 18+ Line 19
21	Carrying Charge on Average Prepaid	$ 9.301	$ 0.491	$ 3.250	$ 3.260	$ 16.302	((Line 14 + 20) * Line 9)
22	Reconciliation Deferral	$ (0.867)	$ 2.434	$ 1.917	$ 6.241	$ 9.725	Line 1 + Line 5
23	Deferred Tax Amount	0.340	(0.955)	(0.752)	(2.448)	(3.815)	Line 22 * 0.39225 *-1
24	Balance Subject to Carrying Charge	$ (0.527)	$ 1.480	$ 1.165	$ 3.793	$ 5.911	Line 22 + Line 23
25	Carrying Charge on Deferral Balance	$ (0.057)	$ 0.161	$ 0.127	$ 0.413	$ 0.643	Line 24 * Line 9
26	Total Carrying Charges	$ 9.244	$ 0.652	$ 3.377	$ 3.672	$ 16.945	Line 21 + Line 25
27	2004 Pension/PBOP Adjustment Amount	11.245	1.998	3.714	4.087	21.044	Page 4, Line 35
28	less: 2004 Pension/PBOP Adjustment Revenue	(12.772)	(1.951)	(3.053)	(3.220)	(20.996)	Per Company Records*-1
29	Prior Period Reconciliation Amount	(1.527)	0.048	0.661	0.867	0.048	Line 27 + Line 28
30	Interest at Prime Rate 4.426%	(0.068)	0.002	0.029	0.038	0.002	Prime rate as per 220 § 6.08(2) * Line 29
31	Past Period Reconciliation Amount	(1.594)	0.050	0.690	0.905	0.050	Line 29 + Line 30
32	**Actual 2005 Pension/PBOP Adjustment Amount**	**8.065**	**1.945**	**4.901**	**6.997**	**21.908**	Line 7 + Line 26 + Line 31

Note 1: This before-tax factor is equal to the after-tax factor of 8.16 percent authorized by the Department.

Note 2: The balances have been reduced to eliminate the amount recovered from transmission customers and non-utility businesses

2004 Pension Adjustment Factor Calculations ($'s in millions)

Line	Description	Boston Edison	Cambridge Electric	Commonwealth Electric	NSTAR Gas	Total	Reference
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G
1	Unamortized Reconciliation Deferral at 12/31/2002	$ 4.198	$ 3.712	$ -	$ -	$ 7.910	Per D.T.E. 03-47-A (Notes 1, 2)
2	2003 Pension & PBOP Distribtuion Expense Sept - Dec	9.869	0.491	4.166	4.656	19.182	Reference: 03-47B
3	less: Pension & PBOP Expense Curr. in Distrib. Rts, 4 mo	(7.728)	(0.316)	(2.408)	(1.606)	(12.058)	Per Company Records (Sept - Dec)*-1
4	2003 Reconciliation Deferral	2.140	0.175	1.758	3.050	7.123	Line 2 + Line 3
5	2003 Reconciliation Adjustment	0.713	0.058	0.586	1.017	2.374	Line 4 / 3
6	Calculated Reconciliation Adjustment For 2004	$ 2.113	$ 1.296	$ 0.586	$ 1.017	$ 5.011	(Line 1 / 3) + Line 5
7	Unamortized Reconciliation Deferral at 12/31/2003	$ 4.225	$ 2.591	$ 1.172	$ 2.033	$ 10.022	Line 1 + Line 4 - Line 6
8	**Carrying Charge Calculation:**						
9	Cost of Capital Factor	10.88%	10.88%	10.88%	10.88%	10.88%	Per D.T.E. 03-47-A (Note 3)
10	Actual Pension Prepaid at 12/31/2002 (Note 4)	$ 140.056	$ 7.205	$ 49.123	$ 47.747	$ 244.131	Reference: 03-47B
11	Actual Pension Prepaid at 12/31/2003 (Note 4)	157.912	8.124	55.385	53.835	275.256	Reference: 03-47B
12	2003 Average Pension Prepaid	148.984	7.664	52.254	50.791	259.694	(Line 10 + Line 11) / 2
13	Deferred Tax on Pension	(47.920)	(2.465)	(16.807)	(16.337)	(83.529)	Line 12 * .82 * 0.39225
14	Pension Balance Subject to Carrying Charge	$ 101.064	$ 5.199	$ 35.447	$ 34.454	$ 176.164	Line 12 + Line 13
15	Actual PBOP Prepaid at 12/31/2002	$ (29.664)	$ (1.526)	$ (10.404)	$ (10.113)	$ (51.707)	Reference: 03-47B
16	Actual PBOP Prepaid at 12/31/2003	(29.970)	(1.542)	(10.511)	(10.217)	(52.240)	Reference: 03-47B
17	2003 Average PBOP Prepaid	(29.817)	(1.534)	(10.458)	(10.165)	(51.973)	(Line 15 + Line 16) / 2
18	Deferred Tax on PBOP	9.707	0.499	3.405	3.309	16.921	Line 17 * .83 * 0.39225
19	PBOP Balance Subject to Carrying Charge	$ (20.109)	$ (1.035)	$ (7.053)	$ (6.856)	$ (35.053)	Line 17 + Line 18
20	Carrying Charge on Average Prepaid	$ 8.808	$ 0.453	$ 3.089	$ 3.003	$ 15.353	((Line 14 + 19) * Line 9)
21	Existing Reconciliation Deferral	$ 4.198	$ 3.712	$ -	$ -	$ 7.910	Line 1
22	Deferred Tax Amount	(1.647)	(1.456)	-	-	(3.103)	Line 21 * 0.39225*-1
23	Balance Subject to Carrying Charge	$ 2.551	$ 2.256	$ -	$ -	$ 4.807	Line 21 + Line 22
24	Carrying Charge on Existing Deferral Balance	$ 0.278	$ 0.245	$ -	$ -	$ 0.523	Line 23 * Line 9
25	Unamortized Reconciliation Deferral at 12/31/03	$ 2.140	$ 0.175	$ 1.758	$ 3.050	$ 7.123	Line 4
26	Deferred Tax Amount	(0.840)	(0.069)	(0.690)	(1.196)	(2.794)	Line 25 * 0.39225
27	Balance Subject to Carrying Charge	$ 1.301	$ 0.106	$ 1.068	$ 1.854	$ 4.329	Line 25 + Line 26
28	Carrying Charge on 12/31/03 Deferral Balance	$ 0.047	$ 0.004	$ 0.039	$ 0.067	$ 0.157	(Line 27 * Line 9) * 1/3 of year
29	Total Carrying Charges	$ 9.133	$ 0.702	$ 3.128	$ 3.070	$ 16.033	Line 20 + Line 24 + Line 28
30	2003 Actual Pension/PBOP Adjustment Amount	-	-	-	-	-	Line 35 prior year true-up
31	less: 2003 Actual Pension/PBOP Adjustment Revenue	-	-	-	-	-	Per Company Records*-1
32	Prior Period Reconciliation Amount	-	-	-	-	-	Line 30 + Line 31
33	Interest	-	-	-	-	-	Prime rate as per 220 § 6.08(2) * Line 32
34	Past Period Reconciliation Amount	-	-	-	-	-	Line 32 + Line 33
35	**Forecasted 2004 Pension/PBOP Adjustment Amount**	**11.245**	**1.998**	**3.714**	**4.087**	**21.044**	Line 6 + Line 29 + Line 34

Note 1: Includes Boston Edison pension deferral of $4.198 million from D.P.U. 92-92
Note 2: Includes Cambridge Electric deferral and carrying charges of $3.712 million from phase-in of SFAS 106 (D.P.U 92-250)
Note 3: This before-tax factor is equal to the after-tax factor of 8.16 percent authorized by the Department.
Note 4: The balances have been reduced to eliminate the amount recovered from transmission customers (3.54%) and non-utility businesses (1.53%).

2007 Pension Adjustment Mechanism
Recoverable Pension and PBOP Plan Expenses For 2006 ($'s in millions)

Line	Account	Boston Edison	Cambridge Electric	Commonwealth Electric	NSTAR Gas	NSTAR Electric & Gas Co. *	Reference
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col G
	Account 926 Employee Benefits (2006)						
1	Allocation Factors 2006 (est.)	50.89%	3.68%	20.40%	25.03%		Utility O&M percentages
2	Allocation Factors 2006 (less unregs) (est.)	54.70%	4.19%	19.84%	20.58%		% of Total Benefits
3	2006 Estimated Total Pension Expense per FAS 87 for all companies					$ 25.007	NSTAR A/C 926100
4	Less Unregulated Companies					(0.173)	Line 3 * (1- sum of Line 2)*-1
5	Pension cost (net of unregs)					$ 24.834	Line 4 + Line 3
6	2006 % of Cap/Benefits (less unreg) (est.)					32.36%	
7	Charged to Capital					(8.036)	Line 5 * Line 6 * -1
8	Pension Expense					$ 16.798	Line 5 + Line 7
9	Recoverable Pension Plan Expense	$ 8.548	$ 0.618	$ 3.428	$ 4.204		Line 1 * Line 8
10	2006 Transmission Labor Allocator (est.)	6.15%	35.29%	3.61%	-		
11	Less: Transmission Component (Electric Only)	(0.526)	(0.218)	(0.124)	-		Line 9 * Line 10 *-1
12	**Distribution Pension Expense**	**$ 8.023**	**$ 0.400**	**$ 3.304**	**$ 4.204**		Line 9 + Line 11
13	2006 Estimated Total PBOP Expense per FAS 106 for all companies					$ 22.336	NSTAR A/C 926320
14	Less Unregulated Companies					(0.155)	Line 13 * (1- sum of Line 2)*-1
15	PBOP cost (net of unregs)					$ 22.181	Line 4 + Line 3
16	Medicare Impact (est.)					$ (11.400)	Per Company Records
17	Medicare Impact (less unregs)					$ (11.321)	Line 16 * (sum of Line 2)
18	64.54% Tax Gross-up					64.54%	
19	Gross-up for Medicare Act reduction					$ (7.307)	Line 17 * Line 18
20	PBOP cost including tax effects of Medicare Act (est.)					$ 14.875	Line 15 + Line 19
21	Charged to Capital Account					$ (4.813)	Line 20 * Line 6 * -1
22	PBOP Expense					$ 10.062	Line 20 + Line 21
23	Recoverable PBOP Plan Expense	$ 5.120	$ 0.370	$ 2.053	$ 2.518		Line 22 * Line 1
24	Less Transmission Component (Electric Only)	$ (0.315)	$ (0.131)	$ (0.074)	-		Line 23 * Line 10
25	**Distribution PBOP Expense**	**$ 4.805**	**$ 0.240**	**$ 1.979**	**$ 2.518**		Line 23 + Line 24
26	**Total Recoverable Distribution Pension and PBOP Plan Expenses**	**$ 12.828**	**$ 0.639**	**$ 5.283**	**$ 6.723**	**$ 25.473**	Line 12 + Line 25

* Total Benefits are charged to Utility Companies from NSTAR Electric & Gas Company. Recoverable amounts under this mechanism include only the components of the accounts attributable to pension and PBOP.

Line	Account	Boston Edison	Cambridge Electric	Commonwealth Electric	NSTAR Gas	NSTAR Electric & Gas Co. *	Reference
27	**Base Rate Pension & PBOP Expenses**						
28	Base Rate Pension & PBOP Expenses for distrib & transm	$ 24.031	$ 1.207	$ 7.371	$ 4.818	$ 37.427	Company Records (03-47; AG-1-31 (Att))
29	2006 transmission allocator (est.)	6.15%	35.29%	3.61%	-		Line 10
30	less: Pension and PBOP currently in rates	$ (22.553)	$ (0.781)	$ (7.105)	$ (4.818)	$ (35.258)	Line 28 * (1-Line 29)*-1
31	**Pension & PBOP Revenues**						
32	2006 Pension/PBOP Adjustment Revenue (est.)	$ (4.843)	$ (1.531)	$ (3.512)	$ (6.902)	$ (16.788)	Per Company Records

Information Request AG-5-8

Based on the response to the three previous questions and a blended current default service rate, please recalculate the bill impact analyses provided in response to AG-2-2. The response should incorporate NSTAR's most recent estimates of what customers' bills will be effective January 1, 2007 by reflecting all rate element changes. To the extent AG-2-2 did not include transmission costs for all transmission cost elements (RNS, LNS, Scheduling and Dispatch, Congestion Management and SCR, System Restoration and Planning, REMVEC, VAR support, NEPOOL/ISO administrative costs, etc.), please include estimates of the excluded elements in this response. Also, include the impact of estimated CPSL program cost adjustments and SIP adjustments. Provide the response in the form of working Excel spreadsheet models with all formulae and cell references in tact as well as a hard copy. Include all supporting documentation, workpapers, calculations and assumptions.

Response

Refer to the responses to Information Request CLC-1-30, Information Request AG-2-1, Information Request AG-2-2, and Information Request DTE-3-7 for bill impact analyses of various scenarios for 2006 rates based on 2005 cost data. Refer to the responses to Information Request AG-5-5, Information Request AG-5-6, and Information Request AG-5-7 for the Companies' latest projections of 2006 deferrals and costs. The Companies will be starting the budgeting process for 2007 shortly and currently do not have data prepared for estimated 2007 Basic Service rates, transmission costs, SIP adjustments, CPSL adjustments, and transition charges.

Information Request AG-5-9

Please refer to the response to Exhibit NSTAR-CLV-1, pages 22-23. For each element of the Test, explain the event or series of events or actions that changed the 1997 Test responses from “No” to “Yes” in 2007. Include the date(s) that each event or action occurred and provide the details of all costs associated with each event/action. Include all supporting documentation, workpapers, calculations and assumptions. Provide a map of the 1997 13.8kV system similar to the one provided in response to DTE-3-12.

Response:

[PROTECTED MATERIALS ATTACHED]

Test of 13.8 kV Facilities	1997		2007
1. Distribution in close proximity to retail customers	No	The new East Cambridge Substation increases the 13.8 kV stations from 3 to 4 stations and is geographically situated in an area that was previously supplied by internal generation. This change reduces the average distance to the retail customer from a 13.8 kV station. The East Cambridge Substation was energized and placed in service at year end 2005 at a cost of $30,905,867. Residual work on the substation was performed in 2006 to energize two more transformers to increase the MVA capacity of the substation.. This allowed for more load to be served to the customers from this station. The additional cost in 2006 to date of upgrading the substation is $1,470,789. The final total cost of the project is not known but NSTAR Electric does not anticipate that additional costs to the station to be substantial.	Yes

2. Distribution radial in character	No	NSTAR Electric has made some modifications to the Cambridge 13.8 kV system since 1997 that had an effect on its operating characteristics. In 1998, Cambridge opened the breakers at two tie-line circuits that interconnected the Prospect substation with Alewife Substation. This was done to reduce the available short circuit at both substations, but had the effect of creating a less integrated, more radial system. In 2005, NSTAR Electric constructed the East Cambridge Substation and is in the process of interconnecting this substation with the Putnam substation via a second 115 kV line. The addition of the East Cambridge Substation (Phase I) and the 115 kV lines (Phase II) supplying it will allow the existing intra-ties to be off loaded from the generator and connected to the East Cambridge Substation thus converting them to radial distribution circuits. Therefore, the Cambridge electrical system will be radial at the 13.8 kV voltage level. The cost of the 115 kV line to-date is $3,682,538. The final total cost of the 115 kV project is unknown at this time	Yes
3. Power flows in, rarely out	No	Referring to Item #2 above, transitioning to a radial distribution system precludes the possibility of power to flow out on the 13.8 kV electric system. The power from the generators will flow out via the 115 kV transmission system.	Yes
4. Power is used not just transported to other market	No	Referring to Item #2 above, configuring into a radial distribution system precludes the possibility of transporting power via 13.8 kV lines to other markets. Power that flows on the 13.8 kV circuits will be used within the confines of the electrical system in Cambridge.	Yes
5. Power is consumed in the area	No	Referring to #2 above, the configuring of the electric system to radial distribution system and the transformation of the generation to the 115kV system will ensure that the power flow out is on the 115 kV transmission system. Power will be transformed to 13.8 kV, 4.16 kV, and lower and will be consumed in the local area of transformation.	Yes
6. Meters are based at the interface	Yes		Yes

7. Low voltage levels	Yes		Yes

Attachment AG-5-9 is hard copy of a map showing the 13.8 kV system for Cambridge in 1997.

Information Request CLC-1-9

Please provide a Working Spreadsheet containing the equivalent of Exhibit NSTAR CLV-5 with NSTAR's forecast 2006 values, including Retail Congestion Management Costs and FERC incentives. If different from NSTAR's forecast, please also provide a version of Exhibit NSTAR CLV-5 that includes all the filed RMR contracts.

Response

Please refer to Attachment CLC-1-9, which includes forecasted 2006 amounts included in the response to Information Request AG-5-5. Retail Congestion Management costs are included in line 4, and FERC incentives are included in line 14. The response does not include an estimation of consolidated rates because this would require year-end 2006 FERC Form 1 data, which is not available. As explained in Exhibit NSTAR-CLV-1, at 17-19, it is not appropriate to include congestion costs in this analysis. Congestion costs continue to be highly variable and forecasted costs for a single year should not be used to infer future results. Please also refer to the response to Information Request AG-3-2 for a discussion of the breadth and scope of congestion costs.

The use of the actual 2005 or forecasted 2006 congestion costs to determine the impact of post-merger congestion costs is not appropriate. The level of congestion costs in those years is irrelevant to the Department's review of the merger transaction. The first year that transmission rates will be consolidated is 2007. There are several factors that make the 2005 and 2006 experience particularly inapplicable with regard to the results in 2007 and beyond, including:

- The $240 million annual Mystic 8 & 9 RMR, which relates to the NEMA congestion zone, may be disallowed or significantly reduced by FERC. Phase 1 of the NSTAR Electric 345 kV Reliability Project, scheduled to be in service this summer, may potentially eliminate the reliability need for at least one if not both Mystic units. Since FERC has set this case for evidentiary hearings, and NSTAR Electric is an intervenor in the case, it would not be appropriate to pre-judge the outcome.

- The existing $30 million annual New Boston RMR (also NEMA) will no longer be needed when NSTAR Electric's 345 kV Reliability Project is completed.

- The existing $350,000 annual Salem Harbor RMR (also NEMA) may no longer be needed due to planned transmission improvements. NSTAR Electric is aware that transmission improvements are contemplated by other utilities that could reduce or eliminate the need for these units to be available for reliability purposes.

- The $118 million annual Fore River RMR, which relates to the SEMA congestion zone, was recently rejected by FERC in a proceeding where NSTAR Electric intervened. However, FERC has invited Fore River to submit a filing to recover its variable costs. Since this has not yet happened and, thus, FERC has not issued a final ruling, it would not be appropriate to pre-judge the outcome. In addition, the units' owner could reapply for RMR treatment in 2007.

- The $5 million annual Potter RMR (also SEMA) was recently rejected by FERC in a proceeding where NSTAR intervened. However, FERC has invited Potter to submit a filing to recover its variable costs. Since this has not yet happened and, thus, FERC has not issued a final ruling, it would not be appropriate to pre-judge the outcome. In addition, the unit's owner could reapply for RMR treatment in 2007.

- Canal, (which is in SEMA) may file for RMR status that would be effective in 2007. NSTAR Electric is aware that Canal currently receives payments as a Local Second Contingency Protection Resource, which are allocated to the load serving entities in SEMA. Since the station is required to maintain system reliability, it is possible that its owner will determine it would financially benefit from an RMR contract, which would significantly impact congestion costs in SEMA. However, NSTAR Electric is unable to predict if or when Canal might file for RMR treatment or the financial implications of such a filing.

- Other generating units serving NEMA, or SEMA, may decide to file for RMR status. Without knowledge of the economic status of each of the existing generators, it is not possible to predict the potential impact on a particular group of customers.

- It is also not possible to forecast the effect of shifting load patterns on congestion costs. NSTAR Electric currently estimates Boston Edison and Cambridge will bear 63 percent and 7 percent, respectively, of any NEMA costs. Similarly, NSTAR Electric currently estimates Boston Edison and Commonwealth will bear 9 percent and 37 percent, respectively, of any SEMA costs. However, in actuality, the burden of any RMR is allocated by ISO-NE based on the respective company's monthly network load as a percent of the total load for the zone. Thus, costs will vary monthly according to relative loads.

NSTAR Electric
Estimated 2006 Retail Transmission Rate
$ in Millions

Line	Description	Consolidated	BECo	Commonwealth *	Cambridge *
	Regional Transmission Costs				
1	Retail RNS Cost	$ 102.358	$ 76.034	$ 18.356	$ 7.967
2	Regional Anciliary Services				
3	Retail Schedule & Dispatch Cost	6.143	4.462	1.218	0.463
4	Retail Congestion Management Cost **	140.527	115.330	10.911	14.285
5	System Restoration & Planning Cost	1.484	1.077	0.305	0.102
6	Load Dispatching (REMVEC)	0.376	0.276	0.090	0.009
7	NEPOOL Administration (Transmission)	0.063	0.056	0.007	-
8	VAR Support Cost	-	-	-	-
9	Total Estimated Regional Transmission Costs	$ 250.951	$ 197.237	$ 30.887	$ 22.828
10	**Local Transmission Costs**				
11	Local Network Service (LNS) Costs				
12	LNS and Scheduling & Dispatch Revenue Req.	Not available	98.290	$ 18.304	$ 19.835
13	13.8kv facilities transferred to Distribution Rates	-	-	-	(13.421)
14	RNS Revenues Received from NEPOOL ***	(99.054)	(85.229)	(10.474)	(3.351)
15	Dispatch Center Revenue Requirement	Not available	4.000	-	-
16	Schedule 1 Revenues Received	(4.375)	(3.624)	(0.149)	-
17	Estimated LNS Revenue Requirement	$ (103.428)	$ 13.438	$ 7.681	$ 3.062
18	**Total Estimated Transmission Costs**	Not available	$ 210.674	$ 38.568	$ 25.890
19	2006 Estimated Billed GWH	21,951.010	15,834.005	4,369.572	1,747.433
20	2006 Estimated Retail Transmission Rate	Not available	$ 0.01331	$ 0.00883	$ 0.01482

* The LNS formula rate for Cambridge and Commonwealth are currently the subject of FERC settlement procedures in Docket ER05-742. The calculations presented in this exhibit are based on the formula tariff as currently under discussion.

** This analysis includes actual forecasted 2006 congestion costs. However, the Companies believe that the amount and future locaion of these costs are too highly uncertain to be used as going forward proxies.

*** Excludes FERC incentives for being part of an RTO and for new transmission investment

Information Request CLC-1-10

Please provide any analysis NSTAR has performed of the effects on customers of consolidating distribution rates across the three NSTAR distribution utilities.

Response

NSTAR Electric objects to responding to this information request. The information sought has no relevance to this proceeding and is not designed to discover relevant information. The Companies are not proposing to consolidate distribution rates in this proceeding and approval of the merger would not necessitate the consolidation of distribution rates. Any rate consolidation proposal would be subject to Department review and approval in the future and would be governed by the terms of the Department-approved Settlement Agreement in D.T.E. 05-85. See Settlement Agreement at ¶ 2.12.

Without waiving this objection, NSTAR Electric states further that it would not be possible to respond to the request. Any such consolidation proposal could not be submitted for effect before January 1, 2010, and would be dependent the rates in effect at the time (which will be subject to adjustment in accordance with the Settlement Agreement), the time over which a "gradual" (Settlement Agreement at ¶ 2.12) phase-in would be proposed and the impact of other rate-structure standards historically applied by the Department.

Information Request CLC-1-11

Please provide the customer impact and total revenue impact by class if NSTAR's distribution rates were consolidated by moving Cambridge and Commonwealth customers to the corresponding Boston Edison tariff, at current rates.

Response

NSTAR Electric objects to responding to this information request. The information sought had no relevance to this proceeding and is not designed to discover relevant information. The Companies are not proposing to consolidate distribution rates in this proceeding and approval of the merger would not necessitate the consolidation of distribution rates. Any rate consolidation proposal would be subject to Department review and approval and are governed by the terms of the Department-approved Settlement Agreement in D.T.E. 05-85. See Settlement Agreement at ¶ 2.12. Moreover, as described below, a distribution rate consolidation proposal would be revenue neutral and not simply move Cambridge and Commonwealth customer to Boston Edison's "current rates." Finally, NSTAR Electric objects because the preparation of such a response would be unduly burdensome, which would outweigh any probative value (of which there is none) of the response.

Without waiving this objection, NSTAR Electric states further that it would not be possible to respond to the request without conducting an analysis that would take months to prepare. Because the availability clauses and rate definitions for Cambridge, Commonwealth and Boston Edison are different, in order to respond, the Companies would need to analyze the usage and load characteristics of individual customers of Cambridge and Commonwealth to determine the appropriate "corresponding Boston Edison tariff". Then after all Cambridge and Commonwealth customers were properly assigned to the correct tariff, their usage characteristics would need to be added to the Boston Edison customers for each class. Then new rates would be developed based on the combined usage characteristics.

It should be noted that if the Companies were to propose a rate consolidation, there would be no revenue impact because they would not move Cambridge and Commonwealth customers to Boston Edison's existing rates, but would perform a revenue-neutral redesign that would be structured to avoid any change in total distribution revenues collected.

Information Request CLC-1-12

For each of the three NSTAR distribution utilities, please provide NSTAR's projection of transition charges in millions of dollars and cents per kWh for each year from 2010 on.

Response

NSTAR Electric objects to responding to this information request. The information sought has no relevance to this proceeding and is not designed to discover relevant information. The Companies are not proposing any change to transition charges in this proceeding and approval of the merger would not affect transition charges.

Without waiving this objection, NSTAR Electric states further that it would not be possible to respond to the request because it has no way of projecting, with any reasonable degree of accuracy, the level of transition charges beginning in 2010. The level of those charges will be affected by numerous factors that will occur between now and 2010 (and thereafter), including, but not limited to: the level of transition costs (which in turn is dependent on such factors as cost inputs and performance of operators of generation with which NSTAR Electric has purchased power agreements and the market price of power); customer load growth, future reductions in the transition charges required in accordance with the terms of the Department-approved Settlement Agreement in D.T.E. 05-85. Under that Settlement Agreement, the Companies are required to reduce their transition charges to offset permitted increases in distribution rates. The size of those increases and the corresponding reductions in the transition charges are dependent on such factors as the rate of inflation and expenditures for certain safety and reliability programs. Without knowing the interplay of all of these factors, it is not possible to prepare an accurate projection of transition charges for 2010 and beyond.

Information Request CLC-1-13

If the transition charges for the three NSTAR distribution utilities were consolidated in 2010, please provide NSTAR's projection of combined transition charges in millions of dollars and cents per kWh for each year from 2010 on.

Response

NSTAR Electric objects to responding to this information request. The information sought has no relevance to this proceeding and is not designed to discover relevant information. The Companies are not proposing any change to transition charges in this proceeding and approval of the merger would not affect transition charges.

Without waiving this objection, NSTAR Electric states further that it would not be possible to respond to the request because it has no way of projecting, with any reasonable degree of accuracy, the level of transition charges beginning in 2010. The level of those charges will be affected by numerous factors that will occur between now and 2010 (and thereafter), including, but not limited to: the level of transition costs (which in turn is dependent on such factors as cost inputs and performance of operators of generation with which NSTAR Electric has purchased power agreements and the market price of power); customer load growth, future reductions in the transition charges required in accordance with the terms of the Department-approved Settlement Agreement in D.T.E. 05-85. Under that Settlement Agreement, the Companies are required to reduce their transition charges to offset permitted increases in distribution rates. The size of those increases and the corresponding reductions in the transition charges are dependent on such factors as the rate of inflation and expenditures for certain safety and reliability programs. Without knowing the interplay of all of these factors, it is not possible to prepare an accurate projection of transition charges for 2010 and beyond.

Information Request CLC-1-20

Please provide the prices for NEMA and SEMA supply for each NSTAR Default Service and Basic Service auction from 2003 to the present.

Response

The Companies object to this request because the information sought is neither relevant to this proceeding nor likely to lead to admissible evidence in the case. The issue as to how Basic Service prices may be combined at the retail level as a result of this proceeding does not require disclosure of the actual wholesale prices received from Basic Service wholesale suppliers. The prices received in the winning bids for NEMA and SEMA supply are directly reflected in the retail prices for Basic Service. Cambridge is located in NEMA, so its Basic Service rates are based on NEMA supply, only. Commonwealth is located in SEMA, so its Basic Service rates are based on SEMA supply. Boston Edison's industrial rates are priced separately for customers in NEMA and SEMA and are based on the wholesale prices for the respective zones. Boston Edison's blended rate for smaller customers is based on 90 percent NEMA supply. Accordingly, because the retail prices track wholesale prices, knowledge of the actual, individual contract prices is meaningless in evaluating the methodology for combining the Companies' Basic Service prices.

Moreover, as the Companies have explained on numerous occasions, the prices NSTAR Electric receives for Basic Service from wholesale suppliers are confidential and disclosure to a market participant, such as the Compact, would be particularly inappropriate. This same issue of disclosure of bid information to the Compact has been raised in the Companies' most recent Basic Service review for July 1st rates and is pending there. Attachment CLC-1-20(a), Attachment CLC-1-20(b), Attachment CLC-1-20(c) and Attachment CLC-1-20(d) are affidavits and comments filed in that proceeding by wholesale marketers who bid to provide Basic Service supplies for NSTAR Electric customers. Those attachments demonstrate that disclosing such information would be harmful to the competitive process and NSTAR Electric's customers. Using the discovery process in this merger proceeding to obtain competitive bid information for the benefit of its load aggregation program and its wholesale supplier in that arrangement is not a proper use of the discovery process and should not be countenanced by the Department.

Without waiving this objection, please refer to Attachment CLC-1-20(e) which provides the Default/Basic Service rates approved by the Department that were derived from NSTAR Electric's Default Service and Basic Service auctions for the years 2003 to the present.

ATTACHMENT CLC-1-20(a)

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Boston Edison Company,	)
Cambridge Electric Light Company, and	)
Commonwealth Electric Company	)
Default Service Rate Filing	)

AFFIDAVIT OF TransCanada Power Marketing Ltd.

Michael E. Hachey, being duly sworn, deposes and says as follows:

1. I am the **Director, Eastern Commercial** for **TransCanada Power Marketing Ltd.** (the "Company"). In this capacity, I am responsible for wholesale and retail power marketing activities, regulatory and governmental affairs.

2. Prior to joining TransCanada, I worked for the New England Power Company where I served in various positions, including Vice President and Director of Generation Marketing, Manager of Independent Power Projects, and Assistant Plant Manager of Brayton Point Station. I received a Master's degree in Electric Power Engineering from Rensselaer, a BS degree in Electrical Engineering from Northeastern, and I completed the Public Utility Executive Program at the University of Michigan. I have served on the NEPOOL Participants Committee and Markets Committees, or their predecessor committees, since 1997 and 1994, respectively, and I am a past member of the Board of Directors of the Northeast Energy and Commerce Association and am a past chairman of the Electric Power Research Institute's Fossil Plant Operations Committee.

3. As **Director, Eastern Commercial**, I participated on behalf of the Company in Boston Edison Company, Cambridge Electric Light Company and Commonwealth Electric Company, d/b/a NSTAR Electric's ("NSTAR Electric") April 19, 2006 Request for Proposals ("RFP") for Power Supply for Default Service by submitting bid information to NSTAR Electric.

4. It is my understanding that, on May 23, 2006, NSTAR Electric submitted bid information relating to the RFP to the Department in Appendix B **CONFIDENTIAL,** pursuant to a Motion for Protective Treatment of Confidential Information.

5. It is also my understanding that Appendix B **CONFIDENTIAL** to NSTAR Electric's May 23, 2006 Default Service filing includes the results of the solicitation for Default Service supply and supporting documentation, including various cost and procurement information relating to the bid information received by NSTAR Electric in response to its RFP.

6. The terms in Appendix B are not, to the best of my knowledge, known beyond NSTAR Electric and relevant regulatory authorities, and within each organization, are known only to a limited number of employees.

7. The Company submitted bids to NSTAR Electric in response to the RFP with the belief that the bid terms would be kept confidential.

8. Bid terms offered by the Company in the context of Default Service solicitations are proprietary to the Company because they reflect key assumptions and estimates made by the Company. The public disclosure of this information will adversely impact the Company's competitive position and provide an unfair and inappropriate advantage to the Company's competitors.

9. Accordingly, Appendix B **CONFIDENTIAL** should be protected from public disclosure to protect the Company's future negotiating position when seeking to market Default Service. Disclosure of such information would inhibit the ability of the Company to participate in the wholesale market for Default Service in the future because other wholesale suppliers of electricity maintain such information as proprietary. If the Company's prices and bid terms become publicly available, the Company may be reluctant to either submit proposals in response to future RFP's issued by NSTAR Electric or to bid the lowest price possible or offer other terms favorable to NSTAR Electric's customers.

Signed under the pains and penalties of perjury this **July 6, 2006**.

Michael E. Hachey

ATTACHMENT CLC-1-20(b)

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Boston Edison Company,	)
Cambridge Electric Light Company, and	)
Commonwealth Electric Company	)
Default Service Rate Filing	)

AFFIDAVIT OF GLEN GRAYEB

Glen Grayeb being duly sworn, deposes and says as follows:

1. I am a Vice President for Sempra Energy Trading Corp (the "Company"). In this capacity, I am responsible for trading and marketing electricity products in the Northeast region of the United States.

2. I have been employed for two (2) years in my current capacity with the Company. I have more than nine (9) years of experience trading and marketing electricity products.

3. I participated on behalf of the Company in Boston Edison Company, Cambridge Electric Light Company and Commonwealth Electric Company, d/b/a NSTAR Electric's ("NSTAR Electric") April 19, 2006 Request for Proposals ("RFP") for Power Supply for Default Service by submitting bid information to NSTAR Electric.

4. It is my understanding that, on May 23, 2006, NSTAR Electric submitted bid information relating to the RFP to the Department of Telecommunications and Energy in Appendix B **CONFIDENTIAL,** pursuant to a Motion for Protective Treatment of Confidential Information.

5. It is also my understanding that Appendix B **CONFIDENTIAL** to NSTAR Electric's May 23, 2006 Default Service filing includes the results of the solicitation for Default Service supply and supporting documentation, including various cost and procurement information relating to the bid information received by NSTAR Electric in response to its RFP.

6. The terms in Appendix B are not, to the best of my knowledge, known beyond NSTAR Electric and relevant regulatory authorities, and within each organization, are known only to a limited number of employees.

7. The Company submitted bids to NSTAR Electric in response to the RFP with the understanding and belief that the bid terms would be kept confidential.

8. Bid terms offered by the Company in the context of Default Service solicitations are proprietary to the Company because they reflect the Company's trade secrets, including its strategic market decisions and view of the market. Thus, if this information were to be publicly disclosed it would harm the Company's competitive position with respect to other participants in the wholesale electricity market.

9. Accordingly, Appendix B **CONFIDENTIAL** should be protected from public disclosure. Disclosure of such information could inhibit the ability of the Company to participate in the wholesale market for Default Service in the future, because other wholesale suppliers of electricity maintain such information as proprietary. If the Company's prices and bid terms were to become publicly available, the Company may be more reluctant to submit proposals in response to future RFP's issued by NSTAR Electric because of concerns that the prices and bid terms contained in such proposals would be similarly disclosed.

Signed under the pains and penalties of perjury this 6th day of July, 2006.

Glen Grayeb

ATTACHMENT CLC-1-20(c)

FPL Energy, 700 Universe Blvd., P.O. Box 14000, Juno Beach, FL 33408
EPM/JB

FPL Energy
Power Marketing, Inc.

July 6, 2006

Mary L. Cottrell, Secretary
Department of Telecommunications and energy
One South Station, 2nd Floor
Boston, MA 02110

Re: NSTAR Electric Basic/Default Service
Request for Disclosure of Information.

Dear Ms. Cottrell:

I am counsel to FPL Energy Power Marketing, Inc. ("PMI"). PMI participated in Boston Edison Company's, Cambridge Electric Light Company's and Commonwealth Electric Company's, d/b/a NSTAR Electric ("NSTAR") April 19, 2006 Request for Proposals for Power Supply for Default Service (the "RFP").

In response to the RFP, PMI submitted to NSTAR Default Service power supply offers that included detailed pricing and other terms as requested by NSTAR (the "PMI Confidential Information"). Subsequently, NSTAR submitted to the Department of Telecommunications and Energy (the "Department") a request for approval of the winning bidders' Default/Basic Service rates for effect July 1, 2006, which was approved by the Department on June 1, 2006. PMI was not a winning bidder.

This letter responds to correspondence submitted by the Cape Light Compact (the "Compact") dated June 21, 2006, wherein the Compact requested that the Department: (i) deny protective treatment for information regarding the proposed charges for "uplift costs" included in the default service rates approved by the Department on June 1, 2006; (ii) disclose such information to the public; and, (iii) disclose to the public any information collected or analysis preformed by the Department to satisfy itself that the estimated uplift costs included in the default service rates are in fact reasonable.

PMI does not wish the PMI Confidential Information be disclosed. The PMI Confidential Information is proprietary to PMI because it is based on: (i) PMI's proprietary views of the market, (ii) PMI's cost/risk calculation algorithms that are also used for other similar RFP responses, and (iii) PMI's tactical and strategic bid profitability targets which, taken together, provide PMI with a competitive advantage in the marketplace. PMI believes that the disclosure of the PMI Confidential Information would cause substantial and irreparable injury to PMI's commercial and competitive positions in the NE-ISO, and other, wholesale power markets.

Please contact me directly at 561.304.5220 with any comments or questions related to this letter.

Sincerely,

Charles Schultz
Managing Attorney

ATTACHMENT CLC-1-20(d)

111 Market Place
Suite 500
Baltimore, Maryland 21202
410.468.3500
410.468.3540 Fax

Constellation Energy
Commodities Group

July 6, 2006

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station, 2nd Floor
Boston, MA 02110

RE: NSTAR Electric Basic/Default Service: Comments Regarding Cape Light Compact's Request for Disclosure of Information

Dear Ms. Cottrell:

On May 23, 2006, Boston Edison Company, Cambridge Electric Light Company and Commonwealth Electric Company, d/b/a NSTAR Electric ("NSTAR Electric") submitted to the Department of Telecommunications and Energy (the "Department") a request for approval of Default/Basic Service rates for effect July 1, 2006, which was approved by the Department on June 1, 2006. In the context of the May 23, 2006 filing, NSTAR Electric provided the Department with confidential bid terms in Appendix B, including wholesale price data and bids for uplift charges. NSTAR Electric filed this information with the Department pursuant to a Motion for Protective Treatment, dated May 23, 2006, which the Department has not acted upon to date. On June 21, 2006, the Cape Light Compact (the "Compact") filed with the Department a request that the Department: (1) reject NSTAR Electric's Motion for Protective Treatment relating to the uplift charge estimates provided in Appendix B; and (2) release this information to the public. On June 27, 2006, the Hearing Officer in this proceeding issued a memorandum (the "Memorandum") that established a deadline of July 7, 2006 to file comments in response to the Compact's request.

Pursuant to the Hearing Officer's June 27, 2006 Memorandum, I am writing on behalf of **Constellation Energy Commodities Group, Inc.** (the "Company") to request that the Department deny the Compact's request for disclosure of Appendix B. **Constellation Energy Commodities Group, Inc.** participated in NSTAR Electric's April 19, 2006 Request for Proposals for Power Supply for Default Service, from which NSTAR Electric's May 23, 2006 filing was derived. Bid terms offered by the Company in the context of Default Service solicitations, including solicitations conducted by NSTAR Electric, are proprietary to the Company because they are based on the Company's strategic market decisions. Accordingly, Appendix B should be protected from public disclosure to protect the Company's future negotiating position when seeking to market Default Service. Disclosure of such information would inhibit the ability of the Company to participate in the wholesale market for Default Service in the future because other wholesale suppliers of electricity maintain such information as proprietary. If the Company's prices and bid terms become publicly available, the Company may be reluctant to either submit proposals in response to future RFP's issued by NSTAR Electric or to bid the lowest price possible or offer other terms favorable to NSTAR Electric's customers.

Sincerely,

David Hannan

David F. Hannan
Senior Counsel

cc: John K. Habib, Esq., Keegan Werlin LLP, 265 Franklin Street, Boston
Jonathan Klavens, Esq., Bernstein, Cushner & Kimmell, P.C., 585 Boylston St., Boston

Boston Edison Company													
Default Service Service Rate History													
Year		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2003	Residential-fixed	5.045	5.045	5.045	5.045	5.045	5.045	6.482	6.482	6.482	6.482	6.482	6.482
	Small C&I-fixed	5.239	5.239	5.239	5.239	5.239	5.239	6.595	6.595	6.595	6.595	6.595	6.595
	Large C&I-fixed-NEMA	5.134	5.134	5.134	5.134	5.134	5.134	6.844	6.844	6.844	6.844	6.844	6.844
	Large C&I-fixed-SEMA							6.110	6.110	6.110	6.110	6.110	6.110
	St Lighting-fixed	5.239	5.239	5.239	5.239	5.239	5.239	6.595	6.595	6.595	6.595	6.595	6.595
	Residential-variable	5.407	5.199	4.805	4.718	4.800	5.287	7.555	7.351	6.019	5.621	5.730	6.251
	Small C&I-variable	5.538	5.314	4.920	4.849	5.123	5.620	7.956	7.769	6.179	5.639	5.707	6.149
	Large C&I-var.-NEMA	5.373	5.173	4.871	4.817	5.039	5.470	7.332	7.167	6.579	6.490	6.461	6.555
	Large C&I-var.-SEMA							7.142	6.978	5.577	5.077	5.198	5.591
	St Lighting-variable	5.538	5.314	4.920	4.849	5.123	5.620	7.956	7.769	6.179	5.639	5.707	6.149
2004	Residential-fixed	6.481	6.481	6.481	6.481	6.481	6.481	6.330	6.330	6.330	6.330	6.330	6.330
	Small C&I-fixed	6.566	6.566	6.566	6.566	6.566	6.566	6.396	6.396	6.396	6.396	6.396	6.396
	Large C&I-fixed-NEMA	6.604	6.604	6.604	6.454	6.454	6.454	7.155	7.155	7.155	6.664	6.664	6.664
	Large C&I-fixed-SEMA	6.165	6.165	6.165	6.048	6.048	6.048	6.945	6.945	6.945	6.540	6.540	6.540
	St Lighting-fixed	6.566	6.566	6.566	6.566	6.566	6.566	6.396	6.396	6.396	6.396	6.396	6.396
	Residential-variable	7.395	7.154	6.579	5.917	5.634	5.967	6.709	6.804	6.102	5.733	6.107	6.441
	Small C&I-variable	7.410	7.218	6.540	6.003	5.823	6.192	6.970	7.096	6.132	5.747	6.007	6.294
	Large C&I-var.-NEMA	6.766	6.591	6.445	6.481	6.332	6.542	7.354	7.497	6.604	6.664	6.664	6.664
	Large C&I-var.-SEMA	6.338	6.155	5.993	6.062	5.914	6.161	7.133	7.276	6.414	6.212	6.284	7.098
	St Lighting-variable	7.410	7.218	6.540	6.003	5.823	6.192	6.970	7.096	6.132	5.747	6.007	6.294
2005	Residential-fixed	7.448	7.448	7.448	7.448	7.448	7.448	7.694	7.694	7.694	7.694	7.694	7.694
	Small C&I-fixed	7.325	7.325	7.325	7.325	7.325	7.325	7.699	7.699	7.699	7.699	7.699	7.699
	Large C&I-fixed-NEMA	8.974	8.974	8.974	7.252	7.252	7.252	8.272	8.272	8.272	9.635	9.635	9.635
	Large C&I-fixed-SEMA	8.709	8.709	8.709	6.705	6.705	6.705	7.470	7.470	7.470	8.843	8.843	8.843
	St Lighting-fixed	7.325	7.325	7.325	7.325	7.325	7.325	7.699	7.699	7.699	7.699	7.699	7.699
	Residential-variable	8.905	8.669	7.477	6.597	6.447	6.971	8.133	8.209	7.248	7.220	7.352	7.989
	Small C&I-variable	8.776	8.649	7.410	6.539	6.463	6.989	8.287	8.316	7.309	7.180	7.310	7.826
	Large C&I-var.-NEMA	9.407	9.409	8.461	7.186	7.172	7.371	8.434	8.688	7.842	9.256	9.497	10.129
	Large C&I-var.-SEMA	9.199	9.205	8.131	6.670	6.610	6.811	7.661	7.803	7.073	8.483	8.757	9.270
	St Lighting-variable	8.776	8.649	7.410	6.539	6.463	6.989	8.287	8.316	7.309	7.180	7.310	7.826

Boston Edison Company													
Default Service Service Rate History													
Year		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2006	Residential-fixed	**12.660**	**12.660**	**12.660**	**12.660**	**12.660**	**12.660**	**11.442**	**11.442**	**11.442**	**11.442**	**11.442**	**11.442**
	Small C&I-fixed	**12.317**	**12.317**	**12.317**	**12.317**	**12.317**	**12.317**	**11.545**	**11.545**	**11.545**	**11.545**	**11.545**	**11.545**
	Large C&I-fixed-NEMA	**18.131**	**18.131**	**18.131**	**9.239**	**9.239**	**9.239**	**11.078**	**11.078**	**11.078**			
	Large C&I-fixed-SEMA	**16.763**	**16.763**	**16.763**	**8.636**	**8.636**	**8.636**	**10.493**	**10.493**	**10.493**			
	St Lighting-fixed	**12.317**	**12.317**	**12.317**	**12.317**	**12.317**	**12.317**	**11.545**	**11.545**	**11.545**	**11.545**	**11.545**	**11.545**
	Residential-variable	**15.547**	**15.449**	**12.529**	**10.248**	**10.043**	**10.587**	**11.886**	**11.942**	**10.535**	**10.456**	**11.124**	**12.184**
	Small C&I-variable	**15.366**	**15.232**	**12.368**	**10.146**	**9.841**	**10.660**	**12.144**	**12.269**	**10.696**	**10.600**	**11.133**	**12.062**
	Large C&I-var.-NEMA	**19.627**	**19.393**	**15.380**	**8.949**	**9.079**	**9.681**	**11.259**	**11.378**	**10.554**			
	Large C&I-var.-SEMA	**18.071**	**17.921**	**14.307**	**8.445**	**8.511**	**8.945**	**10.732**	**10.828**	**9.872**			
	St Lighting-variable	**15.366**	**15.232**	**12.368**	**10.146**	**9.841**	**10.660**	**12.144**	**12.269**	**10.696**	**10.600**	**11.133**	**12.062**

Com Electric													
Default Service Service Rate History													
Year		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2003	Residential-fixed	4.940	4.940	4.940	4.940	4.940	4.940	6.000	6.000	6.000	6.000	6.000	6.000
	Small C&I-fixed	5.132	5.132	5.132	5.132	5.132	5.132	6.057	6.057	6.057	6.057	6.057	6.057
	Large C&I-fixed	4.986	4.986	4.986	4.986	4.986	4.986	6.078	6.078	6.078	6.078	6.078	6.078
	St Lighting-fixed	5.132	5.132	5.132	5.132	5.132	5.132	6.057	6.057	6.057	6.057	6.057	6.057
	Residential-variable	5.295	5.091	4.706	4.620	4.700	5.177	7.089	6.891	5.539	5.127	5.285	5.769
	Small C&I-variable	5.423	5.204	4.818	4.749	5.016	5.503	7.353	7.189	5.614	5.097	5.209	5.615
	Large C&I-variable	5.219	5.025	4.732	4.679	4.894	5.313	6.938	6.778	5.417	4.931	5.049	5.430
	St Lighting-variable	5.423	5.204	4.818	4.749	5.016	5.503	7.353	7.189	5.614	5.097	5.209	5.615
2004	Residential-fixed	5.722	5.722	5.722	5.722	5.722	5.722	6.093	6.093	6.093	6.093	6.093	6.093
	Small C&I-fixed	5.654	5.654	5.654	5.654	5.654	5.654	6.025	6.025	6.025	6.025	6.025	6.025
	Large C&I-fixed	5.739	5.739	5.739	5.875	5.875	5.875	6.741	6.741	6.741	6.281	6.281	6.281
	St Lighting-fixed	5.654	5.654	5.654	5.654	5.654	5.654	6.025	6.025	6.025	6.025	6.025	6.025
	Residential-variable	6.648	6.490	5.655	5.229	5.023	5.228	6.482	6.554	5.798	5.633	5.910	6.076
	Small C&I-variable	6.426	6.372	5.488	5.257	4.987	5.349	6.591	6.706	5.723	5.529	5.675	5.754
	Large C&I-variable	5.944	5.990	5.293	5.889	5.744	5.984	6.928	7.068	6.230	5.890	6.095	6.832
	St Lighting-variable	6.426	6.372	5.488	5.257	4.987	5.349	6.591	6.706	5.723	5.529	5.675	5.754
2005	Residential-fixed	7.133	7.133	7.133	7.133	7.133	7.133	7.171	7.171	7.171	7.171	7.171	7.171
	Small C&I-fixed	7.049	7.049	7.049	7.049	7.049	7.049	7.271	7.271	7.271	7.271	7.271	7.271
	Large C&I-fixed	8.443	8.443	8.443	6.579	6.579	6.579	7.303	7.303	7.303	8.563	8.563	8.563
	St Lighting-fixed	7.049	7.049	7.049	7.049	7.049	7.049	7.271	7.271	7.271	7.271	7.271	7.271
	Residential-variable	8.676	8.449	7.255	6.386	6.234	6.717	7.599	7.589	6.762	6.665	6.827	7.408
	Small C&I-variable	8.575	8.335	7.192	6.353	6.325	6.809	7.759	7.780	6.842	6.727	6.845	7.333
	Large C&I-variable	8.935	8.942	7.898	6.579	6.579	6.579	7.475	7.616	6.905	8.259	8.499	8.964
	St Lighting-variable	8.575	8.335	7.192	6.353	6.325	6.809	7.759	7.780	6.842	6.727	6.845	7.333

Com Electric													
Default Service Service Rate History													
Year		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2006	Residential-fixed	**11.205**	**11.205**	**11.205**	**11.205**	**11.205**	**11.205**	**10.454**	**10.454**	**10.454**	**10.454**	**10.454**	**10.454**
	Small C&I-fixed	**11.011**	**11.011**	**11.011**	**11.011**	**11.011**	**11.011**	**10.461**	**10.461**	**10.461**	**10.461**	**10.461**	**10.461**
	Large C&I-fixed	**16.251**	**16.251**	**16.251**	**8.422**	**8.422**	**8.422**	**10.544**	**10.544**	**10.544**			
	St Lighting-fixed	**11.011**	**11.011**	**11.011**	**11.011**	**11.011**	**11.011**	**10.461**	**10.461**	**10.461**	**10.461**	**10.461**	**10.461**
	Residential-variable	**14.026**	**13.761**	**11.258**	**9.060**	**8.829**	**9.062**	**10.743**	**10.865**	**9.578**	**9.875**	**10.418**	**10.868**
	Small C&I-variable	**13.932**	**13.725**	**11.270**	**9.098**	**8.880**	**9.211**	**10.912**	**11.030**	**9.676**	**9.848**	**10.309**	**10.684**
	Large C&I-variable	**17.536**	**17.390**	**13.880**	**8.225**	**8.301**	**8.725**	**10.417**	**11.019**	**10.185**			
	St Lighting-variable	**13.932**	**13.725**	**11.270**	**9.098**	**8.880**	**9.211**	**10.912**	**11.030**	**9.676**	**9.848**	**10.309**	**10.684**

Cambridge Electric													
Default Service Service Rate History													
Year		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2003	Residential-fixed	4.778	4.778	4.778	4.778	4.778	4.778	6.205	6.205	6.205	6.205	6.205	6.205
	Small C&I-fixed	4.966	4.966	4.966	4.966	4.966	4.966	6.329	6.329	6.329	6.329	6.329	6.329
	Large C&I-fixed	4.845	4.845	4.845	4.845	4.845	4.845	6.378	6.378	6.378	6.378	6.378	6.378
	St Lighting-fixed	4.966	4.966	4.966	4.966	4.966	4.966	6.329	6.329	6.329	6.329	6.329	6.329
	Residential-variable	5.132	4.935	4.561	4.478	4.556	5.018	7.193	6.999	5.739	5.362	5.462	5.958
	Small C&I-variable	5.256	5.044	4.670	4.603	4.862	5.334	7.580	7.401	5.893	5.379	5.441	5.861
	Large C&I-variable	5.079	4.890	4.605	4.554	4.763	5.171	6.872	6.717	6.161	6.077	6.049	6.138
	St Lighting-variable	5.256	5.044	4.670	4.603	4.862	5.334	7.580	7.401	5.893	5.379	5.441	5.861
2004	Residential-fixed	6.141	6.141	6.141	6.141	6.141	6.141	6.068	6.068	6.068	6.068	6.068	6.068
	Small C&I-fixed	6.216	6.216	6.216	6.216	6.216	6.216	6.120	6.120	6.120	6.120	6.120	6.120
	Large C&I-fixed	6.243	6.243	6.243	5.944	5.944	5.944	6.763	6.763	6.763	6.208	6.208	6.208
	St Lighting-fixed	6.216	6.216	6.216	6.216	6.216	6.216	6.120	6.120	6.120	6.120	6.120	6.120
	Residential-variable	7.076	6.932	6.100	5.657	5.407	5.695	6.500	6.567	5.754	5.574	5.852	6.087
	Small C&I-variable	7.062	6.943	6.089	5.721	5.598	5.893	6.736	6.818	5.814	5.582	5.750	5.915
	Large C&I-variable	6.396	6.230	6.093	5.949	5.797	6.099	6.952	7.087	6.243	6.208	6.208	6.208
	St Lighting-variable	7.062	6.943	6.089	5.721	5.598	5.893	6.736	6.818	5.814	5.582	5.750	5.915
2005	Residential-fixed	6.963	6.963	6.963	6.963	6.963	6.963	7.265	7.265	7.265	7.265	7.265	7.265
	Small C&I-fixed	6.854	6.854	6.854	6.854	6.854	6.854	7.272	7.272	7.272	7.272	7.272	7.272
	Large C&I-fixed	8.427	8.427	8.427	6.602	6.602	6.602	7.744	7.744	7.744	9.232	9.232	9.232
	St Lighting-fixed	6.854	6.854	6.854	6.854	6.854	6.854	7.272	7.272	7.272	7.272	7.272	7.272
	Residential-variable	8.449	8.290	7.133	6.246	6.079	6.604	7.694	7.671	6.874	6.781	6.936	7.530
	Small C&I-variable	8.279	8.164	7.008	6.198	6.105	6.619	7.773	7.870	6.898	6.859	6.952	7.200
	Large C&I-variable	8.892	8.894	7.998	6.559	6.509	6.729	7.854	8.075	7.285	8.889	9.126	9.744
	St Lighting-variable	8.279	8.164	7.008	6.198	6.105	6.619	7.773	7.870	6.898	6.859	6.952	7.200

Cambridge Electric													
Default Service Service Rate History													
Year		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2006	Residential-fixed	**12.045**	**12.045**	**12.045**	**12.045**	**12.045**	**12.045**	**10.670**	**10.670**	**10.670**	**10.670**	**10.670**	**10.670**
	Small C&I-fixed	**11.620**	**11.620**	**11.620**	**11.620**	**11.620**	**11.620**	**10.814**	**10.814**	**10.814**	**10.814**	**10.814**	**10.814**
	Large C&I-fixed	**16.890**	**16.890**	**16.890**	**8.598**	**8.598**	**8.598**	**10.149**	**10.149**	**10.149**			
	St Lighting-fixed	**11.620**	**11.620**	**11.620**	**11.620**	**11.620**	**11.620**	**10.814**	**10.814**	**10.814**	**10.814**	**10.814**	**10.814**
	Residential-variable	**15.189**	**14.672**	**11.863**	**9.740**	**9.377**	**9.785**	**11.026**	**11.094**	**9.810**	**9.778**	**10.415**	**11.506**
	Small C&I-variable	**14.856**	**14.292**	**11.798**	**9.653**	**9.336**	**9.802**	**11.528**	**11.597**	**9.875**	**9.985**	**10.459**	**11.111**
	Large C&I-variable	**18.277**	**18.025**	**14.379**	**8.431**	**8.503**	**8.843**	**10.313**	**10.427**	**9.657**			
	St Lighting-variable	**14.856**	**14.292**	**11.798**	**9.653**	**9.336**	**9.802**	**11.528**	**11.597**	**9.875**	**9.985**	**10.459**	**11.111**

Information Request CLC-1-21

Please provide the derivation of the Default Service rates from 2003 to the present for each NSTAR distribution utility, including the winning bid prices and the addition of losses and adders to the bid prices.

Response

The Companies object to this request because the information sought is neither relevant to this proceeding nor likely to lead to admissible evidence in the case. The issue as to how retail Basic Service prices have been developed from wholesale bids in the past is not affected by this proceeding. Moreover, as the Companies have explained on numerous occasions, the prices NSTAR Electric receives for Basic Service from wholesale suppliers are confidential and disclosure to a market participant, such as the Compact, would be particularly inappropriate. This same issue of disclosure of bid information to the Compact has been raised in the Companies' most recent Basic Service review for July 1st rates and is pending there. See Attachment CLC-1-20(a), Attachment CLC-1-20(b), Attachment CLC-1-20(c) and Attachment CLC-1-20(d), which are affidavits and comments filed in that proceeding by wholesale marketers who bid to provide Basic Service supplies for NSTAR Electric customers. Those attachments demonstrate that disclosing such information would be harmful to the competitive process and NSTAR Electric's customers. Using the discovery process in this merger proceeding to obtain competitive bid information for the benefit of its load aggregation program and its wholesale supplier in that arrangement is not a proper use of the discovery process and should not be countenanced by the Department.

Without waiving this objection, please refer to Attachment CLC-1-21(a), Attachment CLC-1-21(b) and Attachment CLC-1-21(c) for the derivation of Basic Service rates for Boston Edison, Cambridge and Commonwealth, respectively, from 2003 to the present. The attachments show the derivation in the same format as filed with the Department each time Basic Service rates are changed.

The derivation is identical each time. For example, the Basic Service rate for residential customers of Commonwealth (Attachment CLC-1-21(c)) starts with Commonwealth's forecast of monthly wholesale load for residential customers, which is reduced by a line-loss factor to determine the monthly retail load. The monthly wholesale price, based on contracts procured through the semi-annual, competitive RFP process, is added to any projected uplift costs not covered by the contract to derive a total wholesale price. The total wholesale price is multiplied by the wholesale load and divided by the retail load to derive the retail price. The Basic Service adder is added to the retail price to compute the total retail price. This is done for each month for the monthly prices and for the six-month period to derive the six-month price.

Boston Edison
Estimated Weighted Average Prices - Based on 6 months 50% bid

	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Residential (Boston Edison NEMA):							
Wholesale Load (MWh)							
Line Loss							
Retail Load (MWh)							
Wholesale Price ($/kWh)							
Uplift Cost ($/kWh)							
Total Wholesale Price ($/kWh)							
Retail Price ($/kWh)							
Total Retail Cost (000's) (w/o Adder)							
Residential (Boston Edison SEMA):							
Wholesale Load (MWh)							
Line Loss							
Retail Load (MWh)							
Wholesale Price ($/kWh)							
Uplift Cost ($/kWh)							
Total Wholesale Price ($/kWh)							
Retail Price ($/kWh)							
Total Retail Cost (000's) (w/o Adder)							
RESIDENTAL Combined							
Default Service Adder							
TOTAL RESIDENTIAL ($/kWh)							

Commercial (Boston Edison NEMA):							
Wholesale Load (MWh)							
Line Loss							
Retail Load (MWh)							
Wholesale Price ($/kWh)							
Uplift Cost ($/kWh)							
Total Wholesale Price ($/kWh)							
Retail Price ($/kWh)							
Total Retail Cost (000's) (w/o Adder)							
Commercial (Boston Edison SEMA):							
Wholesale Load (MWh)							
Line Loss							
Retail Load (MWh)							
Wholesale Price ($/kWh)							
Uplift Cost ($/kWh)							
Total Wholesale Price ($/kWh)							
Retail Price ($/kWh)							
Total Retail Cost (000's) (w/o Adder)							
COMMERCIAL Combined							
Default Service Adder							
TOTAL COMMERCIAL ($/kWh)							

Boston Edison
Estimated Weighted Average Prices - Based on 6 months 50% bid

	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Industrial (Boston Edison NEMA):							
Wholesale Load (MWh)							
Line Loss							
Retail Load (MWh)							
Wholesale Price ($/kWh)							
Uplift Cost ($/kWh)							
Total Wholesale Price ($/kWh)							
Retail Price ($/kWh)							
Total Retail Cost (000's) (w/o Adder)							
Default Service Adder							
Total Retail Price ($/kWh)							
Industrial (Boston Edison SEMA):							
Wholesale Load (MWh)							
Line Loss							
Retail Load (MWh)							
Wholesale Price ($/kWh)							
Uplift Cost ($/kWh)							
Total Wholesale Price ($/kWh)							
Retail Price ($/kWh)							
Total Retail Cost (000's) (w/o Adder)							
Default Service Adder							
Total Retail Price ($/kWh)							

Cambridge Electric
Estimated Weighted Average Prices - Based on 6 months 50% bid

	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Residential (Cambridge NEMA):							
Wholesale Load (MWh)							
Line Loss							
Retail Load (MWh)							
Wholesale Price ($/kWh)							
Uplift Cost ($/kWh)							
Total Wholesale Price ($/kWh)							
Retail Price ($/kWh)							
Total Retail Cost (000's) (w/o adder)							
Default Service Adder							
TOTAL RESIDENTIAL ($/kWh)							
Commercial (Cambridge NEMA):							
Wholesale Load (MWh)							
Line Loss							
Retail Load (MWh)							
Wholesale Price ($/kWh)							
Uplift Cost ($/kWh)							
Total Wholesale Price ($/kWh)							
Retail Price ($/kWh)							
Total Retail Cost (000's) (w/o adder)							
Default Service Adder							
TOTAL COMMERCIAL ($/kWh)							
Industrial (Cambridge NEMA):							
Wholesale Load (MWh)							
Line Loss							
Retail Load (MWh)							
Wholesale Price ($/kWh)							
UpliftCost ($/kWh)							
Total Wholesale Price ($/kWh)							
Retail Price ($/kWh)							
Total Retail Cost (000's) (w/o adder)							
Default Service Adder							
TOTAL INDUSTRIAL ($/kWh)							

Commonwealth Electric
Estimated Weighted Average Prices - Based on 6 months 50% bid

	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Residential (Commonwealth SEMA):							
Wholesale Load (MWh)							
Line Loss							
Retail Load (MWh)							
Wholesale Price ($/kWh)							
Uplift Cost ($/kWh)							
Total Wholesale Price ($/kWh)							
Retail Price ($/kWh)							
Total Retail Cost (000's) (w/o adder)							
Default Service Adder							
TOTAL RESIDENTIAL ($/kWh)							
Commercial (Commonwealth SEMA):							
Wholesale Load (MWh)							
Line Loss							
Retail Load (MWh)							
Wholesale Price ($/kWh)							
Uplift Cost ($/kWh)							
Total Wholesale Price ($/kWh)							
Retail Price ($/kWh)							
Total Retail Cost (000's) (w/o adder)							
Default Service Adder							
TOTAL COMMERCIAL ($/kWh)							
Industrial (Commonwealth SEMA):							
Wholesale Load (MWh)							
Line Loss							
Retail Load (MWh)							
Wholesale Price ($/kWh)							
Uplift Cost ($/kWh)							
Total Wholesale Price ($/kWh)							
Retail Price ($/kWh)							
Total Retail Cost (000's) (w/o adder)							
Default Service Adder							
TOTAL INDUSTRIAL ($/kWh)							

Information Request CLC-1-22

Please provide the equivalent of NSTAR-CLV-4 for NSTAR's Default Service wholesale supply prices.

Response

Please refer to the response to Information Request CLC-1-20.

Information Request DTE-5-13

Refer to the Companies' responses to information requests DTE 2-9, 2-10, 2-11. The Companies indicate that the characteristics of the Cambridge system are changing, and therefore the 13.8 kV lines are now more appropriately characterized as distribution. However, some of the changes cited by the Companies have not yet happened, and are scheduled to occur in the future (e.g., completion of the new East Cambridge substation and installation of a 115 kV line to the new substation (due 4Q 2006); dissolution of intra-ties to Kendall and converting them to radial circuits (due mid-2007). Please explain why the Department should not wait to approve the reclassification of the 13.8 kV lines until after the Companies complete the changes to the Cambridge system.

Response

Under the terms of the Department-approved Settlement Agreement in D.T.E. 05-85, the reclassification of Cambridge's 13.8 kV facilities and corresponding transfer of rate recovery is contemplated to take place at the time of the merger. Moreover, the change in classification must be done at year-end because the FERC tariffs are annual rates based on year-end plant balances and other data from the annual FERC Form 1. Changing classification at any other time frame makes revenue requirement determinations more complex and likely impossible to perform without a tariff change.

The 13.8 kV transfer must be done concurrently with the merger. Since there will be no separate Cambridge FERC Form 1 after the merger date, it would be impossible to perform the formula rate calculation without maintaining separate accounting records after the merger, which would undercut one of the main administrative benefits that the merger provides.

As noted in the response to Information Request AG-5-9, Cambridge's 13.8 kV system has moved away from a transmission system and towards a distribution system. The seven-part test does not provide precise definitions, but requires the exercise of reasonable judgment in determining what classifies as transmission or distribution facilities. However, it is highly unusual for a 13.8 kV system to be classified as transmission. Because many of the changes have moved the character of the system towards distribution, and because many of the final changes will be completed by December 2006, with the remaining during the first half of 2007, it is reasonable to reclassify the system at the time of the merger, for effect January 1, 2007.